CALIFORNIA
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Public Interest Energy Research Program
Energy Systems Integration Team

California's Electricity System of the Future Scenario Analysis in Support of Public-Interest Transmission System R&D Planning

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Abstract

The California Energy Commission (CEC) directed the Consortium for Electric Reliability Technology Solutions to analyze possible future scenarios for the California electricity system and assess transmission research and development (R&D) needs, with special emphasis on prioritizing public-interest R&D needs. The scenarios analyzed in this report are not predictions, nor do they express policy preferences of the project participants or the CEC. The public-interest R&D needs that are identified as a result of the analysis are only one resource to be used by the CEC Public Interest Energy Research (PIER) staff in preparing an R&D plan for the transmission element of the PIER Energy Systems Integration program.

Acknowledgment

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List of Acronyms

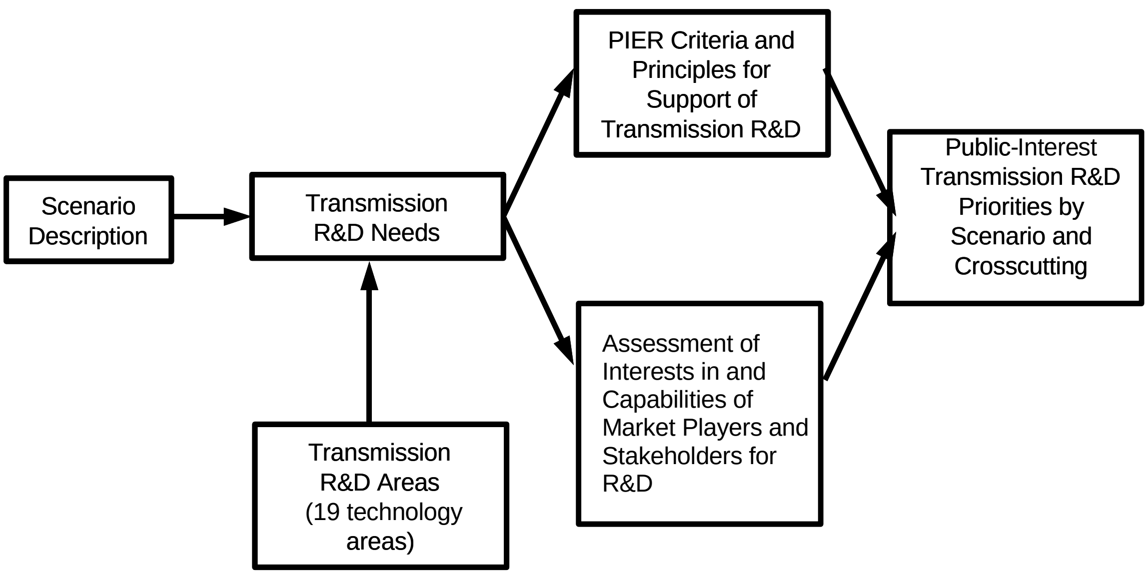
AC	alternating current
AEP	American Electric Power
BPA	Bonneville Power Administration
CDWR	California Department of Water Resources
CEC	California Energy Commission
CAISO	California Independent System Operator
CERTS	Consortium for Electric Reliability Technology Solutions
CPUC	California Public Utilities Commission
CRN	Cooperative Research Network
CSC	convertible static compensator
DR	demand response
DER	distributed energy resources
DOE	U.S. Department of Energy
DC	direct current
EMF	electromagnetic fields
EPRI	Electric Power Research Institute
ESI	Energy Systems Integration
E2I	Electricity Innovations Institute
FACTS	Flexible Alternating Current Transmission Systems
FERC	Federal Energy Regulatory Commission
GIL	gas-insulated line
GMC	grid management charge
GPS	global positioning system
HVDC	high-voltage direct current
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utility
ISO	independent system operator
LADWP	Los Angeles Department of Water and Power
MD02	Market Design 2002
MJ	megajoule
MW	megawatt
MWh	megawatt hour
NAERO	North American Electric Reliability Organization
NERC	North American Electric Reliability Council
NYPA	New York Power Authority
NRECA	National Rural Electric Cooperative Association
NYSEG	New York State Electric and Gas
NYSERDA	New York State Energy Research and Development Authority
PBR	performance-based ratemaking
PDC	phasor data concentrator
PG&E	Pacific Gas and Electric Company
PIER	Public Interest Energy Research Program
PMU	phasor measurement unit

POU	publicly owned utility
PPL	polypropylene paper laminate
PSAM	power system analysis monitor
PPSM	portable power system monitor
ROE	return on equity
RTO	Regional Transmission Organization
R&D	research and development
SCADA	supervisory control and data acquisition
SMES	superconducting magnetic energy storage
SMUD	Sacramento Municipal Utility District
SDG&E	San Diego Gas and Electric Company
SCE	Southern California Edison Company
SMD	Standard Market Design
STATCOM	static synchronous compensator
TCSC	thyristor-controlled series compensator
TVA	Tennessee Valley Authority
UPFC	unified power flow controller
VSC	voltage source converter
WAMS	wide-area measurement system
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
XLPE	extruded dielectric polyethylene

Executive Summary

The California Energy Commission (CEC) directed the Consortium for Electric Reliability Technology Solutions (CERTS) to analyze future scenarios for the California electricity system for the purpose of assessing transmission research and development (R&D) needs, with special emphasis on prioritizing public-interest R&D needs. The scenario analysis involves postulating multiple, alternative, internally consistent future states of the California electricity system as shown in Figure 1. The time horizon for the analysis is the next five years. We develop four scenarios and describe for the evolution of the electricity system that each one represents and the resulting R&D needs. These needs are reviewed using the Public Interest Energy Research (PIER) program criteria for supporting transmission R&D, which involves assessing the R&D interests and capabilities of the players and stakeholders in the California electricity market. The public-interest R&D priorities identified through this process are intended for consideration by CEC along with other input in preparing an R&D plan for the transmission element of the PIER program.

Figure 1. Scenario analysis was used to define public-interest transmission R&D priorities.



It is important to note that the scenarios described in this report are not predictions, nor do they express policy preferences of the project participants or the CEC. They are simply possible future states for the California electricity system intended as a basis for this report's assessment, which has been prepared solely for consideration in CEC PIER's Energy System Integration transmission R&D planning process.

The highest priorities for public-interest R&D – i.e., those that emerge as high priorities in more than one scenario – include (see Table EX-1):

- Real-time grid/asset monitoring and analysis tools for reliability management
- Advanced real-time control technologies and approaches
- Market design, monitoring, and analysis tools
- Transmission planning expansion tools and approaches

There is an immediate need to focus public-interest R&D support on these activities, all of which relate to system reliability and market efficiency. Specifically, they all relate to market design, monitoring, and planning tools as well as advanced controls, areas where roles and responsibilities in California are still evolving and for which there is no existing, established R&D process or funding mechanism. Thus, California public-interest energy R&D funds are critical to address the lack of tools and technologies in these areas.

Somewhat lower public-interest R&D priorities, which emerge either as high priorities in a single scenario or as lower priorities in more than one scenario include:

- Transmission hardware and power-flow control technologies, including energy storage
- Public health, safety, and environmental issues

Table EX-1. Summary of Scenarios and Public-Interest Transmission Priorities

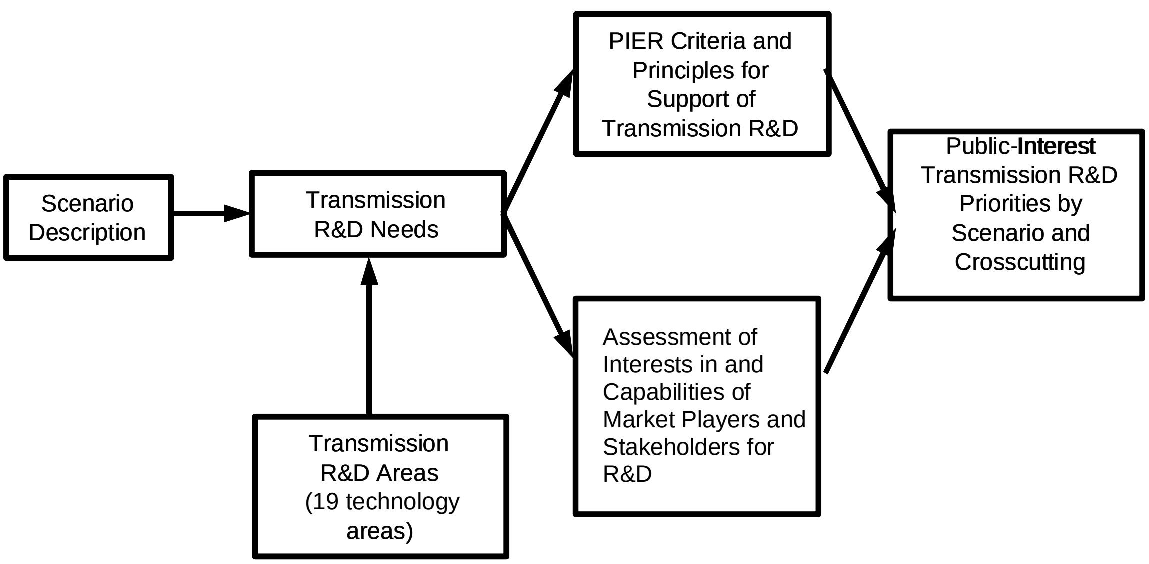
Scenario	**Continuation of Current Trends**	**State-Mandated Solutions**	**Greater Regional Coordination**	**Local Solutions**
Summary	Financial instability, coupled with lack of consensus on future evolution of California electricity system	Policy consensus within California to increase energy self-sufficiency and reliability	Maturing regional processes for equitable sharing of cost and benefits of intra-regional trade	Increased local self-determination and energy self-sufficiency
Key Transmission Issue	Limited investment in transmission	Investment in critical in-state facilities (e.g., Path 15)	Investment in reinforcing regional infrastructure	Investments in local projects for reliability
Highest Public-Interest Transmission R&D Priorities	**A** **E** **F**	**A** **E** **F** **G**	**A*** **E*** **F*** **G***	**A** **E** **F** **G**
Lower Public-Interest Transmission R&D Priorities	**B** **G** **H**	**B*** **D*** **H**	**B*** **D*** **H**	**B** **H**

Key to Technology Research Areas:
A. Real-time grid/asset monitoring and analysis tools for reliability management
B. Transmission power-flow control technologies, including energy storage
C. Transmission hardware technologies
D. Advanced transmission hardware technologies
E. Advanced real-time control technologies and approaches
F. Market design, monitoring, and analysis tools
G. Transmission expansion planning tools and approaches
H. Public health, safety, and environmental issues
*Indicates that public-interest funds shift from a leading to a supporting/enabling role for industry-led R&D activities.
Note that this assessment did not include technology research areas addressed by the PIER Energy System Integration Demand Response and Distributed Energy Resources program elements.

1. Introduction

The California Energy Commission (CEC) directed the Consortium for Electric Reliability Technology Solutions (CERTS) to analyze future scenarios for the California electricity system for the purpose of assessing transmission system research and development (R&D) needs, with special emphasis on prioritizing public-interest R&D needs. The scenario analysis involves postulating multiple, alternative, internally consistent future states for the California electricity system as shown in Figure 1. The time horizon for the assessment is the next five years. We develop four scenarios and describe the evolution of the electricity system and identify the resulting R&D needs for each. The R&D needs are then reviewed in the context of the PIER criteria for supporting transmission R&D, which involves assessing the R&D interests and capabilities of the players and stakeholders in the California electricity market. The public-interest R&D needs identified through this process are intended for consideration by CEC along with other input in preparing an R&D plan for the transmission element of the PIER program.

Figure 1. Scenario analysis was used to define public-interest transmission R&D priorities.



The transmission R&D areas considered in this analysis are listed in Table 1. The list is based on technologies reviewed by the U.S. Department of Energy in the National Transmission Grid Study.[1] However, the list is not exhaustive; R&D activities in the areas of demand response (DR) and distributed energy resources (DER) are discussed but not included explicitly in this analysis because R&D needs for these activities have been or are being addressed by CEC through other planning activities. Appendix A briefly describes each of the R&D activities listed in Table 1.

[1] U.S. Department of Energy. 2002. *National Transmission Grid Study, Issue Papers, Advanced Transmission Technologies*. Washington, DC. http://tis.eh.doe.gov/ntgs/

Table 1. Technologies for Consideration for Inclusion in Scenario Analysis

Technology Categories	Technologies Included
A. Real-time grid/asset monitoring and analysis tools for reliability management	1. Dynamic Transmission Line and Transformer Monitoring and Systems 2. Real-Time Direct System-State Monitors and Wide-Area Measurement Systems (WAMS) 3. Real-Time Grid Operations and Performance Monitoring Tools 4. Grid Analysis Tools 5. Communication Systems for transmission and distribution (T&D) Systems
B. Transmission power-flow control technologies, including energy storage	6. Flexible AC Transmission Systems (FACTS) 7. Energy Storage
C. Transmission hardware technologies	8. Ultra-High Voltage Alternating Current (AC) 9. High-Voltage Direct Current (DC) 10. Underground Cables 11. Transmission Tower Design Tools 12. Advanced Composite Conductors 13. Standardized, Modular Transformers
D. Advanced transmission hardware technologies	14. High-Temperature Super-Conducting Technologies 15. Polyphase Transmission Line Configurations
E. Advanced real-time control technologies and approaches	16. Advanced Real-Time Control Technologies and Approaches
F. Market design, monitoring, and analysis tools	17. Market Design, Performance Assessment, Analysis, and Monitoring Tools
G. Transmission expansion planning tools and approaches	18. Transmission Expansion Planning Tools and Approaches
H. Public health, safety, and environmental issues	19. Assessment of Public Safety, Environmental and Health Effects

The CEC determined that scenario analysis is an especially appropriate approach for public-interest transmission R&D planning because this type of analysis explicitly recognizes the tremendous uncertainty that California's electricity system currently faces. This uncertainty means that a system R&D plan must be robust – focusing on R&D needs as they may emerge under multiple scenarios – and flexible – recognizing that R&D activities may require modifications to ensure their continued relevance as the future unfolds. The time period covered by the scenarios in this report is the five years from 2003 to 2007.

Four scenarios are developed and analyzed:

- Continuation of Current Trends (Muddling Through)
- State-Mandated Solutions
- Greater Regional Coordination
- Local Solutions

It is important to note that these scenarios are not predictions, nor do they express policy preferences of the project participants or the CEC. They are simply possible future states of the California electricity system in which to ground this report's assessment, which has been prepared solely for consideration in CEC's transmission R&D planning process. The scenarios are described using the present tense; the details that make up the scenarios are a combination of circumstances, some of which may be true in the present and some of which are extrapolated.

This paper is organized in six sections following this introduction.

Section 2 discusses the criteria for PIER support for transmission R&D. We used these criteria to develop the priorities for PIER transmission R&D that emerge from the scenario analysis.

Sections 3, 4, 5, and 6 present the analyses of the scenarios. Each section begins with a description of the scenario. The descriptions focus on the roles played by the participants in California's electricity system with an emphasis on their ability to conduct transmission system R&D and their likely interest in doing so. Next, the transmission R&D needs of the electricity system are described for each scenario. This description amounts to a vision of the technological underpinning of the electricity system represented by each scenario. Finally, the findings from the first two elements are assessed in light of the criteria for PIER support for the purpose of identifying priorities for PIER transmission R&D.[2]

Section 7 reviews the findings from the preceding four sections and integrates them into a series of transmission R&D priorities for consideration in the PIER transmission R&D planning process.

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[2] Each scenario assumes that PIER funding will continue and that some level of PIER funding for transmission R&D remains appropriate even though the priorities for PIER funding may change with each scenario.

2. Criteria for PIER Transmission R&D

Through various legislative directives and related R&D planning activities, the CEC PIER program has articulated criteria for R&D activities that are appropriate for PIER support. In this section, we review these criteria, which are used in subsequent sections to assess and prioritize the transmission R&D needs identified in each of the scenarios.

2.1 Criteria for PIER Funding of Transmission R&D

The criteria below are drawn from PIER's enabling legislation and the "Five-Year Investment Plan, 2002 Through 2006 for the Public Interest Energy Research (PIER) Program." These criteria will be used to determine which transmission R&D efforts are appropriate for the state of California to fund through the PIER Program.

Research initiatives and projects must meet all four criteria.

- Criterion 1. R&D activities that improve the quality of life for California citizens.

Improvements in environmental quality; public health and safety; energy cost/value; and electricity system reliability, quality, and sufficiency are all California interests that should be advanced by PIER research activities.

- Criterion 2. R&D activities that improve the efficiency and reliability of the electricity transmission system.

- Criterion 3. R&D activities that advance science or technology.

- Criterion 4. R&D that is unlikely to be adequately provided by the competitive or regulated research sectors.

Issues addressed have "social and public interests" that are not accounted for by market pricing mechanisms.

Applying Criterion 4 ("Pure Public Interest" R&D)

"Pure public interest" R&D refers to efforts to develop "basic information" that is non-exclusive and cannot be appropriated by the research sponsor.

A significant segment of public-interest R&D does not meet the "pure public interest" standard, and additional criteria, listed below, must be applied to determine what R&D should be funded under this rubric.

Additional considerations include:

1) Development risk is too high and/or development time horizon too long for private sector

alone to invest in the R&D, but California public benefits payoff is substantial.

2) Technology development costs are too high for private sector alone to invest in the R&D, but California public benefits payoff is substantial.

3) Market and regulatory barriers/uncertainty would inhibit successful implementation of the activity, but California public benefits payoff is substantial, and a reasonable path exists for government to work with industry to mitigate barriers and/or uncertainty.

2.2 Use of the Criteria

Using the criteria above to justify PIER support for transmission R&D activities means that, for this scenario analysis, we need to describe the expected benefits of R&D activities clearly and, most important, explain exactly why the market alone will not effectively capture these benefits. To accomplish the latter goal, we identify specific reasons why the market might undervalue certain R&D activities in each of the scenarios. We describe the responsibilities and incentives of market participants to pursue R&D in each scenario and use these descriptions to identify the reasons why the market alone may not invest appropriately or adequately in needed transmission R&D. We make explicit reference to the criteria listed above in our analysis.

We focus initially on evaluating the interests and incentives of the principal California market players for addressing needed transmission R&D: the California Independent System Operator (CAISO), investor-owned utilities (IOUs), municipal utilities, water districts, publicly owned utilities (POUs), the Western Area Power Administration (WAPA), marketers, generators, merchant transmission owners, and equipment manufacturers. For completeness, we also consider other stakeholders whose actions affect or influence R&D, including California state agencies (excluding the CEC's role in managing PIER), the Western Electricity Coordinating Council (WECC), the North American Electric Reliability Council (NERC), the Federal Energy Regulatory Commission (FERC), and the U.S. Department of Energy (DOE).

We do not separately consider the R&D activities that the Electric Power Research Institute (EPRI) might pursue for two reasons: 1) traditional EPRI R&D activities are assumed to be addressed implicitly in evaluating the interests and incentives of IOUs and POUs because these entities are the primary sponsors of EPRI's R&D – that is, R&D that EPRI pursues is assumed to be a reflection of the R&D that their primary sponsors pursue (IOUs and POUs), and 2) EPRI R&D activities that might be pursued through the newly created Electricity Innovations Institute (E2I) are assumed to be broadly consistent with those identified for PIER or DOE because, similar to the reasoning used for traditional EPRI R&D, the R&D needs of these and other public-sector sponsors are the target market for E2I research. Moreover, to date, no completed E2I research offerings are available to evaluate.

3. Scenario 1 – Continuation of Current Trends (Muddling Through)

The first scenario projects current trends into the future and establishes a starting point for the development of the scenarios, which follow. As noted above, this scenario is not a prediction or an expression of a policy preference; it is an extrapolation of some but not all aspects of the current electricity situation in California.

3.1 Scenario 1 Description

The central features of this scenario are:

The financial uncertainty, institutional conflict, and lack of resolution resulting from the California "electricity crisis" of 2001 continue. As an example, Pacific Gas and Electric Company (PG&E) is unable to emerge from bankruptcy in a timely fashion because of continued conflict with the California Public Utilities Commission (CPUC). Similarly, FERC decisions on refunds for energy overcharges in California in 2001are delayed and, once made, are challenged, leading to additional delays. There is incomplete resolution of differences in vision between FERC and the state over the structure and organization of wholesale electricity markets. Federal energy legislation on electricity does not clarify FERC jurisdictional roles, leading to ongoing state challenges of federal authorities regarding the organization of electricity markets.

Merchant generators are slow to return to financial health. As a result, construction on many merchant plants is halted, and other plants are cancelled. Significant public opposition and lack of clarity about roles and economic benefits is successful in blocking the siting of new power plants and major new transmission lines or leads to protracted delays in projects. For example, growing public concern regarding health risks of high-voltage electricity transmission continues unabated. Local groups organize successfully to create a hostile environment for would-be power plant developers.

Regional demand growth is moderate, consistent with recent trends (2001 is considered an exception). California demand growth lags behind regional growth because of a continuing depressed economy and state budget crisis. Supply is unable to keep pace with demand. Efforts to use pricing approaches to ration supplies during tight periods are mired in ideological (and sometimes misleading) debates over alleged wealth transfers among customer classes. CAISO must again implement rolling blackouts.

The upgrade of Path 15 continues to be delayed, and outages in the corridor sever Northern and Southern California for extended periods.

Organization and operation of the transmission system is characterized as follows:

CAISO continues to operate transmission assets owned by IOUs. Municipal utilities continue to operate their transmission assets independent of CAISO.

Wholesale market design means that CAISO will transition to Market Design 2002 (MD02), yet there is significant reliance on price caps in lieu of more basic, structural remedies.

The incentives for IOU transmission investment are determined initially by FERC's authorized, regulated Return on Equity (ROE). However, although FERC has increased these rates modestly in recent years (and considers even greater incentives to promote certain structural and investment activities), the effect of these incentives is mitigated by CPUC-authorized retail tariffs. A politically popular retail rate freeze, in the absence of other cost cutting by the utilities, undercuts the effect of higher FERC-authorized ROEs.

Moreover, because of reliance on an ROE approach for rewarding transmission investment, there is no relationship between the impact of transmission limits on market operations and incentives to upgrade the transmission system. IOUs focus on generation interconnection and local reliability upgrades, and transmission projects needed for market efficiency continue to face an uncertain future particularly because the resultant higher consumer costs are a “pass-through” item.

Transmission planning continues using the current the process led primarily by IOUs; there is growing awareness of the need to account for economic efficiencies yet there are no widely accepted planning tools to support these assessments. State oversight is limited. The process is dominated (and utility staff is overwhelmed) by generation interconnection requests (increasingly for plants that fail to materialize). Regulatory policy direction is inconsistent regarding priorities of economic efficiency versus reliability. There is still no coordinated regional process for addressing approval of multi-jurisdictional lines.

Reliability management continues with the present form of NERC/WECC oversight, in which financial penalties for non-compliance are minimal. Information-sharing among operators for reliability management is negotiated on a bilateral basis; operators have growing yet limited access to information about conditions on neighboring systems.

3.2 Transmission R&D Needs

For the transmission system, a continuation of current trends translates to minimal investment in and construction of new lines. This trend is driven by a lack of capital for construction activities resulting from the financial condition of the large IOUs in the state. In addition, the uncertain financial incentive to earn a return on transmission system capital investment significantly weakens the business justification for new construction. Moreover, the general negative public attitude toward the need for new transmission facilities increases the transaction costs of new construction, creating additional disincentives. The result is minimal (zero would be desirable from the standpoint of some) capital investment in the transmission system.

As a result of little or no investment in new transmission lines, the strategy for operation of the transmission system is to maximize the utilization of existing facilities with very little investment in new equipment. From an engineering point of view, the strategy is to seek higher ratings (thermal, voltage, or stability) on existing equipment and the overall system at the lowest possible cost.

No new transmission lines of significant length or new substations to promote market efficiency are built except as a last resort and only with appropriate regulatory guarantees of cost recovery. Additions are made to keep the existing system just in step with demand to address reliability concerns. A few short line sections are constructed to solve very specific transmission flow problems, and incremental additions to substations are considered. Because these short sections and incremental substation additions interface directly with the existing system, opportunities to use new transmission technologies are minimal.

High-voltage DC (HVDC) lines are not considered because they are most economical for long distances. HVDC "Light" is considered as a solution to a particular power-flow problem. High-phase-order transmission is probably not considered because of the minimum lengths required (at least 20 to 30 miles). Advanced AC controllers [e.g., Flexible Alternating Current Transmission Systems (FACTS) and phase angle regulators], although very desirable, are difficult to justify because of their high cost, utilities' risk aversion and limited experience with these devices, and the fact that their benefits are primarily in reducing "pass-through" costs. Nevertheless, R&D for more reliable, lower-cost AC controllers for which there is more operating experience could accelerate the application of these devices.

Among the alternatives for increasing the ratings of existing transmission lines are raising the voltage to higher levels or increasing current ratings. Raising the voltage level typically requires modifications to towers and a change-out of line insulators. Increasing the current rating is accomplished by replacing the conductor. The extent of tower modifications depends on the conductor selected. More tower modifications are needed as the weight of the replacement conductor increases. Several new conductor designs are in various stages of development and testing. Typically, these new conductors replace steel with a lower-modulus material and are operated at higher temperatures to increase the current rating. Further development and testing of these new conductors will provide more options for upgrading existing transmission lines. In both of these upgrade alternatives, tower design tools are used to examine the existing towers and determine the required modifications for larger conductors or higher voltages.

The long-distance configuration of the transmission system in California means that voltage control and transient stability issues must be carefully addressed. For improved voltage control, fast reactive power sources are needed. For improved stability control, fast real power sources are needed. Advanced AC power controllers can provide both types of control; however, the application of them is complex, and each installation requires custom engineering. Energy storage technologies can also be used to reduce transmission stability constraints or voltage constraints.

Increased real-time monitoring and analysis of the power system offers the greatest short-term potential for improving operations and relieving thermal, voltage, and stability constraints. The benefits to be gained are large compared to the implementation costs. Typically today's system measurements are of voltage and current at the substation level. One challenge has been to fully utilize all the information available in the measured data. The complexity of the power system and its dynamic network means that matching measured data to theoretical models continues to be a challenge. For monitoring very dynamic changes on the system, such as voltage and stability, specialized measurement equipment such as the wide-area measurement system (WAMS) is being developed and tested. Continued improvement is needed in sensors to monitor various parameters on conductors, transformers, and other components in order to fully utilize their capacities.

In addition to the hardware needed to enable greater real-time monitoring, a variety of software enhancements are required to translate and convert the data collected into meaningful information to support operating decisions. Software engineering is required for data-base management and advanced computational and decision-support tools along with visualization and human-machine interface technologies. In the mid-term, exploration and prototyping is needed for new automatic control schemes that complement and enhance the control capabilities of human operators.

Maintaining the existing system becomes especially important when the addition of new facilities is limited and there is limited spare capacity. The existing transmission system has been installed over a period of years, so determining the actual service life of each piece or type of equipment is an arduous and uncertain task. The ability to monitor the service life or condition of equipment becomes necessary as a means of extending equipment life. In addition, live-line maintenance techniques and tools are needed as in-service time requirements increase. At some point, certain lines cannot be taken out of service for maintenance, and maintenance cannot be performed during certain system loading conditions.

Public health, safety, and environmental concerns are addressed as necessary, but improvements may be difficult to accomplish. Blackouts and power outages directly affect the public. The extent of the impact will depend upon the number and severity of these events and the resulting social costs. Brownouts, poor voltage control, poor power quality, and harmonics disrupt public and commercial activity. It is necessary to prevent the natural tendency toward immediate political solutions from supplanting the need for advanced planning and emergency response training. When the voltage or current of existing lines is upgraded, special design and engineering are required to maintain safe levels of electric and magnetic fields at the edges of rights-of-way.

Many of the regulatory and market issues that underlie Scenario 1 will be best resolved by unbiased research on these issues by parties free of financial interests in the outcomes.

3.3 Assessment of Public-Interest Transmission R&D Priorities

This analysis begins with an evaluation of the interests and incentives of market players and stakeholders. It concludes (in Section 3.4) with an assessment of public-interest R&D priorities for Scenario 1, which are the R&D needs identified in Section 3.2 that would not be pursued adequately by market players and stakeholders in the absence of PIER support.

CAISO

CAISO was set up as an operating entity and has no history of significant R&D budgets. In addition, extreme cost pressures to lower grid management charges (GMCs) limit the availability of funds to support R&D. The focus of CAISO's R&D priorities is on incremental improvements leading to direct operational costs savings and compliance with reliability rules. There is little focus on fundamental efforts to improve overall market efficiencies/design.

IOUs

R&D funds are scarce because of the financial condition of the state's IOUs and the uncertainties facing the IOUs. Available funds for R&D are allocated only to short-term efforts that will lead to immediate (i.e., in less than one year) operational cost savings. Operational management of the interconnected grid and associated R&D is viewed as CAISO's responsibility.

POUs

Although POUs in principle have greater financial ability than IOUs to support R&D, POUs are smaller, so their budgets are modest in comparison to the spending by IOUs on R&D prior to restructuring. Moreover, only a handful of the state's POUs own significant transmission assets. Similarly, although public ownership might suggest a greater willingness to adopt longer time horizons for R&D investments and greater concern for public-interest R&D than would be true of privately owned entities, POUs have not, in the past, focused extensively on R&D and therefore lack the internal infrastructure for conducting R&D activities.

An exception is the Cooperative Research Network (CRN) of the National Rural Electric Cooperative Association (NRECA). However, CRN focuses on R&D investments that emphasize local distribution R&D, especially in rural settings consistent with the characteristics of the territories served by CRN members; CRN does not focus on transmission R&D.

Merchant Transmission Owners

These entities are not viable in this scenario.

Generators

Generators' business incentives are limited to transmission R&D that lowers interconnection costs. However, the precarious state of generator finances in this scenario mean that R&D is considered a non-essential expenditure and will thus not be supported.

Marketers

Marketers conduct internal R&D focused on software tools and data acquisition and processing systems for analyzing the market and assessing financial risk. Larger marketers develop and maintain these tools in house. High internal R&D costs are necessary because of continued, rapid change in the markets.

Equipment Manufacturers

Equipment manufacturers cannot commit to R&D unless it addresses the most basic transmission equipment for which there is a defined market, such as conductors, towers, and transformers. Even in these cases, incentives to invest are dampened because of continued uncertainty regarding the changing business climate for the manufacturers' principal clients: the utilities. There is little or no incentive to invest in advanced transmission technologies because of uncertainty about market size, timing, and who will use (and who will pay for) the technologies.

State Agencies (other than CEC PIER)

State agencies other than CEC have a continuing interest in R&D to support the public good but a limited mandate to pursue transmission system R&D because CEC is the designated lead for energy R&D in the state. In any case, these agencies have limited ability to support R&D through taxpayer funding because of reduced state budgets and other budget priorities that take precedence over investment in R&D.

WECC/NERC

Historically, WECC and NERC have focused on developing guidelines and criteria for reliability management. Currently, they are seeking better tools for assessing compliance with reliability rules. R&D is not viewed as their mandate, and they cannot raise funds from members to support development of new tools for this mission because their members are independent system operators (ISOs) like CAISO and the IOUs and POUs described above.

FERC

FERC is seeking better tools for analysis of market designs, assessing compliance with market rules, and detecting gaming of markets as well as tools for after-the-fact market monitoring. FERC has limited ability to raise funds from within the federal government to fully support development of needed new tools for this mission, except through cooperative programs administered by DOE.

DOE

DOE has as a growing leadership role to play in formulating electricity transmission policy for the nation. DOE R&D programs seek to address emerging gaps in needed public-interest transmission R&D. Principal clients/stakeholders are ISOs, NERC, and FERC. DOE has limited ability to raise funds from federal government to support these activities because other federal spending priorities take precedence. DOE actively seeks to leverage funds with leading state R&D agencies [e.g., CEC and the New York State Energy Research and Development Authority (NYSERDA)].

3.4 Recommended Public-Interest Transmission R&D Priorities

Virtually all transmission R&D can be justified in Scenario 1 as R&D that will serve the public interest and will not be pursued adequately by the private sector. Thus, the task is to determine the highest priorities among all the transmission R&D activities considered.

Highest Priorities include:

A. Real-time grid/asset monitoring and analysis tools for reliability management

Keeping the lights on in the absence of new transmission construction is of paramount importance in this scenario. Software tools are the lowest-cost, quickest-to-implement approaches to improving system reliability when compared to the alternative of advanced transmission technology, such as FACTS devices, which, in fact, would also require better real-time monitoring and tools to be utilized effectively.

E. Advanced real-time control technologies and approaches

Increased real-time monitoring is a technology that enables real-time control. Real-time control technologies provide the flexibility needed to efficiently schedule transactions within and across the power system, which is less costly than investments in transmission hardware.

F. Market design, monitoring, and analysis tools

In Scenario 1, there is no functioning market. Thus, market design analysis tools and approaches are essential for developing and "laboratory" testing new market designs prior to implementation. When these new designs are put in place, aggressive market monitoring tools will be needed to detect emerging market flaws in real time so that action can be taken to mitigate them before they grow to crisis proportions.

Lower Priorities include:

B. Transmission hardware and power-flow control technologies, including energy storage

A number of advanced transmission technologies would allow for greater utilization of existing transmission corridors; these technologies are more costly than software tools yet less costly than construction of new transmission facilities. R&D to lower the costs and improve the reliability of these technologies will advance their market acceptance and further delay the need for construction of new facilities.

G. Transmission planning expansion tools and approaches

At some point, the increased power transfers that can be supported with better monitoring and software technologies as well as advanced real-time technologies will necessitate the construction of new transmission facilities. Tools or analysis approaches are needed that can account for both the reliability and economic impacts of potential new facilities in a manner integrated with other (e.g., non-transmission) options for addressing these needs (i.e., enhanced reliability, improved market efficiency) so that tradeoffs can be fairly assessed.

H. Public health, safety, and environmental issues

Scenario 1 posits continuing unplanned blackouts and brownouts because of a delayed upgrade of Path 15. In this context, state actions, especially in the area of R&D, would increasingly be coordinated with the actions of other federal agencies (such as the newly created Office of Homeland Security). Emergency preparedness would be a core element of these activities, however, and would likely also be coordinated with similar activities affecting other vital infrastructures, such as natural gas.

Given public concern regarding the health effects of electromagnetic fields (EMFs) associated with high-voltage transmission, state-led studies or studies coordinated with appropriate national entities are needed.

Transmission technology R&D that might reduce the health effects of high-voltage transmission could also be a priority. The primary means of reducing these impacts is to place lines underground. Although the technologies for undergrounding are mature, undergrounding involves greatly increased construction costs and additional siting and permitting costs relative to what is necessary for aboveground lines. Reducing these costs requires capturing economies of scale from large-scale undergrounding activities, not more R&D.

4. Scenario 2 – State-Mandated Solutions

Scenario 2 can be viewed as one possible reaction to or transition from Scenario 1; in Scenario 2, strong state leadership results in increased coordination of electricity planning and operations within the state yet leaves unresolved many coordination issues in the West as a whole.

4.1 Scenario 2 Description

The central features of this scenario are:

State actions and final bankruptcy court rulings allow IOUs to return to financial health. The state actively supports long-term transmission investments to increase reliability as well as a revamped, integrated resource planning process. This process includes renewed emphasis on energy efficiency and renewable energy sources. The focus of planning efforts is on increased reliance on in-state resources to enhance reliability as well as continued access to regional markets and out-of-state resources.

FERC defers to state-led decisions on wholesale electricity market organization and structure. FERC rulings on refunds contribute to renewed financial health of IOUs. Availability of imports is reduced somewhat because of unresolved market inconsistencies between California and the rest of the West, which further increases the need for and justifies the construction of additional in-state generation.

A state-directed integrated resource planning processes facilitates the siting of in-state generation in locations that relieve intra-state transmission bottlenecks. Transmission system enhancements give greater consideration to reliability-enhancing investments over those that might facilitate increased interstate trade for economic purposes. The state orders IOUs to build needed transmission projects and further streamlines regulatory processes, leading to greater coordination among state agencies for approval and siting of new generation and transmission facilities.

Demand growth continues at modest 1990s levels, moderated somewhat by state-directed energy efficiency and local DER (including customer-owned, locally sited renewables) programs, which, together, reduce the electricity demand that must be met through the high-voltage transmission system. Increased reliance on in-state resources versus lower-cost (at least, in the short-term) out-of-state resources leads to moderate electricity price increases. However, there is no major reform of retail tariff structures (i.e., limited movement toward real-time pricing); thus, there is no significant demand response to dampen wholesale market price volatility. In any case, the final cost of electricity is significantly decoupled from wholesale market prices because the bulk of customer demand is met through long-term (fixed-priced) contracts.

Stringent local air quality restrictions limit utilization of conventional back-up generation and fossil fuel-fired DER, so DER development is limited.

Organization and operation of the transmission system is characterized as follows:

CAISO, with a state-appointed board, continues to operate transmission assets owned by IOUs; municipal utilities continue to operate their transmission assets independent of CAISO. MD02 is fully implemented. Reliance on price caps is eased because greater state involvement (e.g., directing and streamlining the process for construction of needed power plants) reduces in-state supply-demand imbalances. Aggressive market monitoring sharply limits opportunities to unfairly exploit market power.

FERC-regulated ROE is coordinated with CPUC to ensure meaningful opportunities for recovery under regulated tariffs. For example, CPUC issues Certificates of Public Need based largely on CAISO recommendations, thereby lowering IOUs' uncertainty regarding cost recovery for transmission investments.

At the same time, there is an evolving mixture of private and public ownership of the transmission system. State-led directives to expand transmission may be carried out by third parties operating under long-term contracts with IOUs, or new transmission facilities may even be owned by the state.

Transmission planning emerges as one element of the state-led integrated resource planning process, which is tightly coordinated with CEC supply and demand assessments. Opinions differ regarding assessment of the economic efficiency and reliability benefits of increased transmission and evaluation of tradeoffs with alternatives (local generation, DR, etc.) There is still no coordinated regional process for addressing either planning or approval of multi-jurisdictional lines.

Reliability management is reformed through the creation of the North American Electric Reliability Organization (NAERO). There are meaningful financial penalties for non-compliance with reliability rules. Still, information-sharing among system operators for reliability management continues to be negotiated on a bilateral basis.

4.2 Transmission R&D Needs

In Scenario 2, IOUs are once again able to invest prudently in the transmission system because capital is available for utilities to improve their own transmission systems. Because the transmission line siting process is streamlined and coordinated within the state, the uncertainty of investing in new transmission projects is reduced. Conditions are such that more in-state generation is brought to the market for interconnection to the grid, reducing the need to add long-distance transmission from out-of-state generation sources.

The transmission strategy pursued by each utility in this scenario is to add sufficient transmission capacity to relieve congestion and increase flexibility in power transfers within its service territory. CAISO provides a planning overlay and introduces statewide considerations to these activities. With the addition of new lines, each utility seeks to reduce the thermal, voltage, and stability constraints in its service territory. The placement and connection of local generation near load centers further strengthens the network of each individual utility. Long-distance transmission to existing out-of-state generation is maintained at about the same level. Over time, this trend translates into a smaller fraction of total electricity consumption being delivered to the state via long-distance transmission. Each utility seeks ways to control the flow of power across its service territory.

As the possibility of building new transmission lines opens up in this scenario, the question becomes how to design a line and maximize it for immediate needs as well as future flexibility. In the past, several types of designs have allowed for future flexibility and expansion. For example, an oversized conductor and towers can be installed to allow for future growth, and substation capacity can be added as needed. In addition, double-circuit towers can be installed, initially with just one circuit, or a tower structure can be installed with an underbuild allowing for a lower-voltage circuit to be added in the future. In another design, the towers and insulators are installed to support a higher voltage, but the line is initially operated at a lower voltage. The substation can be designed for dual voltage, and additional capacity can be added when the voltage is switched to the higher level. The Pacific Inter-tie is an excellent example of a design allowing for future expansion. The original rating when the line was commissioned in 1969 was 1.4 GW; the line was upgraded in voltage to 2 GW and then in current to 3 GW, all with the same conductors and towers that were originally installed.

HVDC lines are not considered because they are most economical for long distances. HVDC "Light" is considered as a solution to very special power-flow problems. Both HVDC Light and advanced AC controllers are considered for regulating power flows across a utility's service territory. Serious consideration is given to back-to-back AC-DC-AC conversion stations at key interstate interfaces; however, costs are prohibitive in light of realistic economic or reliability benefits. High-phase-order transmission could be considered to strengthen the medium-voltage network by conversion of existing double-circuit lines. Upgrading of existing lines in either voltage or current is considered as a secondary option to the installation of new lines.

With additional transmission capacity installed, the examination of a broader range of technology options becomes more feasible. In some cases, these technologies move from being the only options to playing supporting roles. Further development of real-time monitoring, analysis, and control of the power system continues to be a priority.

Although there are few unique technical issues associated with interconnecting remote renewable generation sources, increased reliance on these resources means additional focus on ensuring that the integration of large numbers of remotely sited renewables does not create new reliability challenges.

Public health, safety, and environmental issues in this scenario can be addressed in a coordinated and rational manner with leadership, direction, and assistance from the state. With increased in-state generation, the environmental effects of long-distance transmission will diminish in priority compared to the effects associated with increased numbers of new in-state generating plants.

4.3 Assessment of Public-Interest Transmission R&D Priorities

The analysis of R&D priorities begins with an evaluation of the interests and incentives of market players and stakeholders. It concludes (in Section 4.4) with an assessment of the public-interest R&D priorities for this scenario, which are the R&D needs identified in Section 4.2 that will not be pursued adequately by market participants in the absence of PIER support.

CAISO

Continued cost pressures to lower GMCs (because of unresolved market design problems that are of a "regional" nature and result in higher overall operating costs) limit availability of funds to support R&D. The focus of R&D is similar to that in Scenario 1, on incremental improvements with direct operational costs savings or for compliance with reliability rules. There is less emphasis on R&D to improve market efficiencies except in so far as they might lower GMCs (although lowering GMCs may not always be consistent with the public interest, e.g., if lowering GMCs increases risk of blackouts or raises system costs in total).

IOUs

IOUs are better able to make R&D investments in this scenario because they have become financially solvent again and have better access to capital. A primary focus of these investments will be on regulated distribution assets, which they both own and control. Because there remains a disconnection between ownership (IOUs) and operation (CAISO) of transmission assets, IOU R&D investments may not be optimal unless there is strong regulatory oversight. For example, an IOU may not choose to invest in R&D to reduce congestion because the resulting reductions in congestion costs will not be captured by the IOU. That is, the natural focus of R&D investments will be on benefits that can be captured by the utility; there is little motivation for the utility to focus on R&D that addresses state, regional, or global issues.

POUs, Merchant Transmission, Equipment Manufacturers, WECC/NERC, FERC

For these entities, there are no significant differences in R&D priorities from those identified in the Scenario 1 (Section 3.3).

DOE

In Scenario 2, DOE may take a more "hands off" view of R&D support for California in keeping with overall deference by the federal government to the state on wholesale market issues.

4.4 Recommended Public-Interest Transmission R&D Priorities

In Scenario 2, there is less pressure for the State to support a broad spectrum of public-interest R&D than in Scenario 1 because IOUs will be better able to support R&D activities that provide more local (i.e., internal to the utility) benefits. Construction of new, long transmission lines for reliability and economic purposes (not just generator interconnection) becomes more likely.

However, reliability-enhancing projects will take precedence over projects that provide principally economic benefits (especially those oriented toward supporting increased trade into California).

Highest Priorities include:

A. Real-time grid/asset monitoring and analysis tools for reliability management
E. Advanced real-time control technologies and approaches
F. Market design monitoring and analysis tools

The above three research areas remain a high priority in Scenario 2 for the same reasons as are detailed in Scenario 1. In particular, interest in market design analysis tools increases as a more robust electricity market develops.

G. Transmission planning expansion tools and approaches

Transmission expansion planning tools and approaches increase in priority in Scenario 2 because the increased ability to build new lines in this scenario carries with it the need to judiciously site and select the lines to be constructed. The process of siting and building new lines involves many parties, both public and private, that review, scrutinize and question proposed plans. The need to respond to the myriad of issues and concerns raised by these participants greatly increases the options that must be considered in the planning process and results in modified approaches to line selection and choice relative to past practices. Improved tools for expansion planning should help speed the process and lead to better alternatives and choices for consideration by all involved parties.

Lower Priorities include:

B. Power-flow control technologies, including energy storage

A number of advanced transmission technologies allow for greater utilization of existing transmission corridors, thereby permitting construction of new transmission facilities to be deferred. The application of these technologies may be of more interest for lower-voltage transmission lines. Controlling the relatively modest power flows handled by lower-voltage lines offers a means of introducing advanced control technologies at lower cost and risk rather than introducing large-scale controllers for the highest transmission voltages. R&D to lower the costs and improve the reliability of these technologies advances their market acceptance.

However, the focus shifts from one of support principally by CEC to one of support from CEC to cosponsor IOU-led R&D activities. Hardware technologies remain the domain of private companies, which own the intellectual property and stand to benefit from widespread deployment of these technologies.

D. Advanced transmission hardware technologies

With the construction of new lines comes the opportunity to utilize advanced technology, which ranges from new materials and designs for transmission towers and line configurations to advanced conductors. Advanced technologies promise to increase transfer capabilities and/or reduce costs but must maintain at least the same levels of reliability. As with previously discussed technology areas, focus shifts from one of support principally by CEC to one of support from CEC to cosponsor IOU-led R&D activities. Again, hardware technologies remain the domain of private companies, which own the intellectual property and stand to benefit from widespread deployment of these technologies.

H. Public health, safety, and environmental issues

Similar focus and justifications to those in Scenario 1.

5. Scenario 3 – Greater Regional Coordination

Scenario 3, in which greater coordination and leadership for electricity planning and operations emerge among the Western states, can be viewed as a distinct reaction to or transition from Scenario 1. Nevertheless, unresolved issues remain regarding how coordination is actually implemented.

5.1 Scenario 3 Description

The central features of this scenario are:

A unified market design for the entire WECC is supported through the creation of three large western-states RTOs. There is substantial region-wide trade among wholesale power producers and load-serving entities.

Harmonization of interests increases (but is not complete) among states as well as federal land management agencies and Native American tribes. Jurisdictional conflicts are reduced (but not eliminated) under greater FERC oversight.

The state further streamlines its regulatory processes, allowing for meaningful coordination with regional planning and siting bodies for approval and siting of new generation and transmission facilities. However, these regional bodies are still in their formative stages. Procedural steps and coordination between/among them and state and federal agencies are not yet seamless.

There is a healthier climate for private investment in new generation relative to the climate in previous years, which leads to an improved overall regional supply-demand balance. Still, as a result of the meltdown of 2001, financial markets remain slow to provide capital to the once-vibrant merchant power plant sector.

Demand growth increases to 1980s levels as the economy responds, in part, to the renewed health and increased stability of wholesale electricity markets.

Locational marginal pricing of transmission creates tangible incentives to locate generation closer to load and provides one element for a more comprehensive framework for enabling greater DR. There is a significant increase in the fraction of customers exposed to prices that more closely reflect time-varying, wholesale market conditions than has been true under past tariff practices.

Organization and operation of the transmission system is characterized as follows:

CAISO and publicly owned transmission facilities within California are subsumed into one of the three large, western-states RTOs. The current mixture of private and public ownership of transmission continues, with modest merchant transmission investment along certain high-value corridors.

FERC's Standard Market Design (SMD) is implemented. Aggressive market monitoring sharply limits opportunities for unfair exploitation of market power in wholesale electricity markets.

Performance-based ratemaking (PBR) for IOUs provides meaningful financial rewards to transmission owners for investments and other operational improvements to reduce congestion costs. FERC's regulatory decisions provide greater certainty than is the case currently for recovery of merchant investment.

Transmission planning occurs, in principle, within the context of overall resource planning that is conducted though a regional process with significant coordination among state planning agencies and transmission owners. In reality, the newness of the processes, despite the historic familiarity of the major players with one another, leads to false starts.

Reliability management evolves so that NAERO defers to the RTOs for intra-RTO reliability management. Still, there are meaningful financial penalties for non-compliance with reliability rules governing inter-RTO movements of power. There is a significant increase in region-wide sharing of operational information for reliability management.

5.2 Transmission R&D Needs

The greater regional coordination in this scenario assumes a regional-transmission-operator model for the western transmission system, which is to be operated by several well-coordinated RTOs. Because the transmission line siting process is coordinated within the state and streamlined, uncertainty regarding investment in new projects is reduced. The financial condition of the utilities and transmission operators allows reasonable investment in transmission facilities. Financing is available for in-state generation, and pricing encourages the location of generation near load centers. Merchant transmission system investment is encouraged through the regulatory process. Dynamic pricing for customers offers the potential for real-time market controls.

The transmission strategy is to build new lines to better interconnect the RTOs and to reduce congestion and connect new generating plants near load centers within each RTO. Regional interconnections utilize either AC controllers or HVDC back-to-back converters to achieve a high degree of power-flow control between regions. These interconnections are planned to create a better overall high-voltage transmission network ("superhighway") to facilitate regional power transactions. Merchant transmission lines target opportunities where the profit potential is greatest, such as dedicated lines for new generating resources or short- to medium- length lines that are key to connecting RTOs (analogous to turnpikes in the national highway system). Better methods to control loads responsive to dynamic pricing are developed as a means to reduce transmission loading and congestion.

With tariffs in place to provide financial incentives to reduce congestion costs, the emphasis on power-flow control methods increases. HVDC back-to-back converters, HVDC "Light," and advanced AC power-flow controllers are considered to reduce congestion. IOUs, RTOs, and merchant transmission companies consider installing these power-flow controllers. In addition, merchant transmission companies consider development of techniques, tools, software, and services for congestion management and control.

Superconducting transformers, cables, generators, motors, and fault current limiters are being developed for power transmission systems. When they become commercially available, they will offer higher current ratings, smaller physical dimensions, and reduced weight compared to the equipment they would replace, which uses copper or aluminum conductors. The ratings for superconducting cables are expected to be three to eight times higher than for conventional cables; superconducting transformers will have larger overload capabilities with a smaller footprint than their conventional counterparts. All of the superconducting equipment will have lower resistance losses than conventional equipment. The initial market for this equipment will likely be retrofits in which the initially higher capital costs of the equipment can be offset by the higher avoided costs associated with the alternative of installing a new facility. For example, a single high cost superconducting cable retrofit could offset the need to install 3 to 5 copper cables for a given amount of power transfer capacity.

The exchange of real-time information over a wide area becomes critical in this well-coordinated RTO environment. With sufficient transmission capacity and pricing incentives, the operation of the system moves from congestion and crisis management to efficiency scheduling and optimum flow-control management. The WAMS architecture is modified to fit the RTO model and fully implemented.

Overall, reliability improves as the transmission system is further developed to meet anticipated demands. Transmission power outages are more limited and infrequent. With greatly improved transmission system reliability and power system control, large-scale blackouts become extremely rare events.

Transmission line construction still raises public health concerns, and the visual impact of transmission lines continues to be objectionable to some. In some areas, the greatly increased cost of undergrounding new or existing lines is judged acceptable. Other design strategies for minimizing electric and magnetic fields are also undertaken to reduce public health concerns and visual impacts.

5.3 Assessment of Public-Interest Transmission R&D Priorities

This analysis begins with an evaluation of the interests and incentives of market players and stakeholders. It concludes with an assessment of public-interest R&D priorities for Scenario 3, which are the R&D needs identified in Section 5.2 that will not be pursued adequately by market participants in the absence of PIER support.

CAISO

Rationalized regional markets lead to lower GMCs, which increase the opportunities for funding R&D. Still, unless CAISO is restructured into a for-profit entity (which is not likely), CAISO has limited incentives to emphasize R&D outside of its core mission to manage reliability (similar to Scenario 2).

IOUs

IOUs in this scenario have even greater ability to make R&D investments because of the coordinated state, regional, and federal “buy-in.” Scenario 3 postulates a performance-based ratemaking (PBR) regime for IOUs, which aligns R&D investments with “system” benefits (e.g. cost-effective reductions in congestion costs). There is greater recognition of (and agreed upon formulas for sharing) regional benefits of certain R&D activities.

POUs, Generators, and Marketers

No significant differences from Scenario 1 with respect to extent of investment/ability to invest in R&D.

Merchant Transmission

A modest emerging role is assumed for merchant transmission in this scenario. However, the business necessities of merchant transmission firms are such that their focus is on purchasing off-the-shelf technologies. R&D investments are very short term and related only to maintenance and operability of transmission assets; investments in newer, novel technologies are not undertaken.

Equipment Manufacturers

R&D priorities for equipment managers are similar to the priorities identified in Scenario 1. However, R&D costs are lower in Scenario 3 because of more stable market designs. Because of greater certainty about the stability of markets, manufacturers are more able to make investments that support creation of commercial products than is the case in Scenario 1.

NAERO

NAERO R&D priorities are similar to those in Scenario 1, but NAERO has greater ability in Scenario 3 to raise R&D funds from members.

FERC

Similar to scenario 1.

DOE

DOE has a somewhat greater ability in Scenario 3 to increase federal funding to support R&D (compared to Scenario 2) consistent with greater federal support for regional resolution of transmission issues.

5.4 Recommended Public-Interest Transmission R&D Priorities

In Scenario 3, the number of public-interest R&D priorities is reduced relative to the number identified in the other scenarios; the priorities in Scenario 3 focus on core activities and activities that are least likely to be supported by the private sector – security, safety, public health, etc. because this scenario envisions a world in which many public-interest R&D needs are increasingly addressed by the private sector (IOUs, equipment vendors, etc.).

Highest priorities include:

A. Real-time grid/asset monitoring and analysis tools for reliability management
E. Advanced real-time control technologies and approaches
F. Market design monitoring and analysis tools
G. Transmission planning expansion tools and approaches

In Scenario 3, the highest priority R&D topic areas remain the same as those in Scenario 2; however, the focus of the R&D efforts for each topic area shifts. Because many public-interest R&D needs are addressed by the private sector in this scenario, public-interest R&D can turn toward a broad range of fundamental or more basic enabling research and development activities as well as toward encouraging adoption of new analytical techniques, methods, and technologies.

The R&D focus shifts in this scenario to ensuring a smooth transition from basic research to demonstration activities with significant financial involvement of private-sector partners. Significant cost sharing by partners is expected so that the bulk of public-interest R&D support can target project development and evaluation rather than the costs of demonstrations.

Special needs arise for R&D that explicitly addresses issues emerging from greater regional coordination. A regionally coordinated power system increases the requirement for monitoring and control of transmission assets. The use of real-time control technologies provides the flexibility needed to efficiently schedule transactions within and across a regional power system. Similarly, planning approaches need to explicitly consider the regional context within which planning is taking place.

Lower priorities include:

B. and D. Advanced transmission hardware and power-flow control technologies, including energy storage

The ability to control power transfers will greatly facilitate regional coordination. The RTOs postulated in this scenario use advanced hardware and power-flow controllers to minimize congestion on their networks and enhance power transfers across each individual network. As in Scenario 2, CEC's role shifts to supporting utility-led R&D activities in this area.

H. Public health, safety, and environmental issues

Similar focus and justification to those in Scenario 1.

Increased transmission line construction does not call for additional public-interest R&D to reduce perceived health impacts or visual concerns. As noted in Scenario 1, the technologies for reducing these impacts (i.e., undergrounding) are mature and well established. Cost reductions will occur primarily through economies of scale resulting from greater reliance on these technologies.

6. Scenario 4 – Local Solutions

Scenario 4 can be viewed as a possible reaction to or transition from Scenario 1 or as representing a situation that might coexist with all three of the previous scenarios. In Scenario 4, overall dependence on the transmission system is reduced because electricity services are increasingly provided and managed on a local basis. As a result, the focus of this scenario depends less on the features of transmission system organization and more on the features of the distribution system. We draw principally on Scenario 1 for the features of the larger electricity system in which local action to provide electricity service takes place.

6.1 Scenario 4 Description

The central features of this scenario are:

Local governments and organizations assume a significant role in energy planning, leading to increased reliance on distributed generation, locally sited renewables, and energy efficiency. There is movement toward municipalization of IOU assets in selected metropolitan and regional areas across the state.

Low-cost fuel cells and other new small-scale generation technologies are successfully commercialized within five years. Technical costs of interconnection are lowered significantly relative to today's costs.

State policies promote reliance on small-scale generation. Regulatory utility and local environmental barriers to DER are successfully reduced. Local building inspectors and code officials adopt a proactive posture toward on-site generation facilities.

Significant public opposition is successful in blocking the siting of new, large generating stations and major transmission lines, in part because smaller, local solutions have become more viable as alternatives to reliance on large, centralized power sources and systems of delivery.

Differences continue between FERC and the state regarding the structure and organization of wholesale electricity markets. This conflict contributes to impending wholesale supply shortfalls because of underinvestment in generation and transmission at the state and regional levels.

Demand growth continues at 1990s levels, moderated somewhat by locally directed energy efficiency programs and local DER programs.

There is a significant increase in the fraction of customers exposed to dynamic prices, including self-generation (which provides additional demand elasticity). This leads to increased volatility in loads served by transmission system.

Negative health effects of transmission lines are conclusively proven, reinforcing public sentiment against construction of new high-voltage transmission lines.

Stringent environmental restrictions on greenhouse gases are enacted. The state supports additional movement toward renewables and clean, locally sited DER.

Organization and operation of the transmission system is characterized as follows:

Same as for Scenario 1.

6.2 Transmission R&D Needs

In Scenario 4, increased reliance on small-scale generation, distributed generation, locally sited renewables, and energy efficiency reduces the rate of growth in the demand placed on the transmission system. As in Scenario 1, there is significant public opposition to the siting of new transmission lines, and multi-jurisdictional approval is uncertain. The financial condition of utilities allows only minimal investment in transmission facilities. There is continued reliance on low-cost, out-of-state generation, but little is done to increase the state's access to these resources.

The strategy for the transmission system is, as in Scenario 1, to maximize utilization of existing facilities with a reasonable addition of new equipment. Upgrading of existing transmission facilities is preferred over new line construction because of siting difficulties. Existing long-distance transmission lines delivering out-of-state generation are maintained. Better methods to control loads responsive to dynamic pricing are developed as a means to reduce transmission loading.

Connection of many renewable and distributed generating units affects lower-voltage transmission lines and substations. It is necessary to address issues related to physically connecting many small generating units and optimally controlling/coordinating their operation with the operation of the bulk power transmission system. The ability to add substation capacity in small increments is desirable in this scenario; modular substations and energy storage technologies are examined as a means to incrementally add or defer substation capacity. Short-length lower-voltage transmission lines connecting substations may be necessary to build a network based on increased local generation.

Slowly growth in transmission demand and upgrading of existing lines reduces transmission congestion problems only modestly. Techniques to manage congestion and other operating line constraints are still needed. Use of real-time data for managing the system continues to be a priority. A faster system (WAMS) is needed to monitor voltage and stability constraints to improve transmission network management.

As more customers are exposed to dynamic pricing, there is a need for system operators to improve their methods for accommodating and taking advantage of demand response to improve operations. These include technologies, integrated with existing monitoring and control systems, to better predict, monitor, track, and react to large-scale demand responses.

With increased reliance on small-scale generation, distributed generation, and renewables, which are located closer to populated areas than traditional large generation facilities, comes an increase in public safety issues. In addition, there will be issues related to safety of utility workers who construct, operate, and maintain these facilities. The environmental issues (principally, air emissions) associated with significant reliance on small-scale and distributed generation (typically in urban areas) need study and analysis beyond what has previously been undertaken. Public opposition to new transmission lines fosters a continued examination of the health effects of these lines.

6.3 Assessment of Public-Interest Transmission R&D Priorities

This analysis begins with an evaluation of the interests and incentives of market players and stakeholders. It concludes with an assessment of the public-interest R&D priorities for Scenario 4, which are the R&D needs identified in Section 6.2 that will not be pursued adequately by market participants in the absence of PIER support.

CAISO, IOUs, Merchant Transmission, Generators, Marketers, Equipment Manufacturers, FERC and other organizations

For all but the POUs, the incentives for investment in transmission R&D remain similar to those faced by these parties in Scenario 1.

POUs

POUs in Scenario 4, including newly created municipal distribution utilities, have potentially greater ability (funding/commitment) to support R&D because of increased attention to energy planning and the role of R&D in enabling greater energy self-sufficiency. Nevertheless, it is difficult to imagine POU-supported R&D emphasizing anything but local considerations/benefits (i.e., there will be limited interest in transmission R&D or in the impacts on the transmission system of significant penetration of DER).

6.4 Recommended Public-Interest Transmission R&D Priorities

In Scenario 4, similar to Scenario 1, most transmission R&D can be justified as serving the public interest and will not be pursued adequately by the private sector. Therefore, the task is to sort out the highest priorities among the whole range of transmission R&D activities.

Highest priorities include:

The highest priorities identified in Scenario 1 would also be high priorities Scenario 4. However, in Scenario 4, greater emphasis would be placed on R&D devoted to the integration of DER because of the greater presence of these resources in this scenario.

A. Real-time monitoring and tools applied to distribution system, including power quality

The focus of real-time monitoring and control tools expands in this scenario to cover not only the bulk transmission system but also the distribution system because of the growing penetration of DER.

G. Integrated transmission and distribution system planning

The ability to locate, install, and operate distributed generation in the most effective manner necessitates development and implementation of new methods to plan the distribution system and account for interactions with the transmission system.

Note: The PIER Distribution Energy Resources R&D program becomes more important in this scenario, especially the program's system integration elements.

Lower priorities include:

H. Local public health, safety, and environmental issues

In this scenario, public opposition to siting and constructing new utility facilities is assumed. Therefore, additional state-led studies or studies coordinated with appropriate national entities regarding health effects of EMFs associated with high -voltage transmission are needed.

Although outside the scope of the PIER Transmission R&D program, research on air quality impacts of DER located in urban environments and mitigation techniques is needed.

Note: Techniques are needed for managing/protecting two-way flows of electricity on distribution grids. To ensure speedy acceptance of distributed generation, interconnection issues need to be resolved so that owners face least investment costs and public safety is ensured. As noted previously, these issues are already being addressed to some degree by the CEC PIER ESI Distributed Energy Resources program.

7. Summary and Analysis of Findings

This section integrates the findings from the four preceding scenario analyses to develop a short list of public-interest R&D priorities for the CEC to consider for inclusion in a five-year transmission R&D plan. The highest priorities in the list are those that emerged as high priorities in more than one scenario. These priorities are robust and therefore are likely warranted for inclusion in a core set of public interest R&D priorities. In addition to priorities that ranked high in more than one scenario, some priorities that ranked high in only one scenario or appeared as lower priorities in more than one scenario are also highlighted, if a strong rationale has been identified to justify their inclusion.

The highest priorities, which emerge as high priorities in more than one scenario, include (see Table 2):

A. Real-time grid/asset monitoring and analysis tools for reliability management
E. Advanced real-time control technologies and approaches
F. Market design, monitoring, and analysis tools
G. Transmission planning expansion tools and approaches

There is a clear need to focus public-interest R&D support on A, E, F, G, which all relate to system reliability and market efficiency. Specifically, these activities relate to market design, monitoring, and planning tools as well as advanced controls, which are all areas where roles and responsibilities are still evolving in California and there is no past, established R&D process or funding mechanism. Thus, it is critical to use California public-interest energy R&D funds to address the lack of tools and technologies in these areas.

Somewhat lower priorities, which emerge either as high priorities in one scenario or lower priorities in more than one scenario include:

B. Transmission hardware and power-flow control technologies, including energy storage
H. Public health, safety, and environmental issues

Hardware technologies included in category B (as well as those in categories C and D in Table 2 below) necessarily remain the domain of private companies, which own the intellectual property and stand to benefit from widespread deployment of these technologies. California should encourage cost-shared demonstration of these technologies through the utilities and regional consortia.

Table 2 summarizes the placement in each scenario of the transmission R&D technologies assessed.

Table 2. Summary of Recommended Public-Interest Transmission R&D Priorities

Scenario Technology	Continuation of Current Trends	State-Mandated Solutions	Greater Regional Coordination	Local Solutions
A. Real-time grid/asset monitoring and analysis tools for reliability management	**H**	**H**	**H***	**H** (integrated with distribution system operations)
B. Transmission power-flow control technologies, including energy storage	**L**	**L***	**L***	**L**
C. Transmission hardware technologies				
D. Advanced transmission hardware technologies		**L***	**L***	
E. Advanced real time control technologies and approaches	**H**	**H**	**H***	**H**
F. Market design, monitoring, and analysis tools	**H**	**H**	**H***	**H**
G. Transmission expansion planning tools and approaches	**L**	**H**	**H***	**L** (integrated with distribution system planning)
H. Public health, safety, and environmental issues	**L**	**L**	**L**	**L** (focused on local issues)

Priorities: H – Highest; L – Lower; * - Supporting role for PIER; e.g., cost-sharing IOU-led R&D demonstrations

Appendix A: Descriptions of Transmission Technologies

The primary objectives, benefits, barriers to deployment, and commercial status of each technology considered for inclusion in the scenario analysis conducted to support development of CEC PIER ESI transmission R&D plan are described in this Appendix.

Technologies Considered for Inclusion in Scenario Analysis

Technology Categories	Technologies Included
A. Real-time grid/asset monitoring and analysis tools for reliability management	1. Dynamic Transmission Line and Transformer Monitoring and Systems 2. Real-Time Direct System-State Monitors and Wide Area Measurement Systems (WAMS) 3. Real-Time Grid Operation and Performance Monitoring Tools 4. Grid Analysis Tools 5. Communications for Transmission and Distribution (T&D) Systems
B. Transmission power-flow control technologies, including energy storage	6. Flexible AC Transmission Systems (FACTS) 7. Energy Storage
C. Transmission hardware technologies	8. Ultra-High Voltage Alternating Current (UHV AC) 9. High-Voltage Direct Current (HVDC) 10. Underground Cables 11. Transmission Tower Design Tools 12. Advanced Composite Conductors 13. Standardized, Modular Transformers
D. Advanced transmission hardware technologies	14. High-Temperature Superconducting (HTSC) Technologies 15. Polyphase Transmission Line Configurations
E. Advanced real-time control technologies and approaches	16. Advanced Real-Time Control Technologies and Approaches
F. Market design, monitoring, and analysis tools	17. Market Design, Performance Assessment, Analysis, and Monitoring Tools
G. Transmission expansion planning tools and approaches	18. Transmission Expansion Planning Tools and Approaches
H. Public health, safety, and environmental issues	19. Assessment of Public Safety, Environmental and Health Effects

1. Dynamic Transmission Line and Transformer Monitoring Systems

The capability of the electricity grid is restricted through a combination of the limits on individual devices and the composite loadability of the system. Improving monitoring to determine these limits in real time and to measure the system's state directly can increase the grid's capability. The operation of most of the individual devices in a power system (such as transmission lines, cables, transformers, and circuit breakers) is limited by each device's thermal characteristics; in simple terms, trying to put too much power through a device will cause it to heat excessively and eventually fail. Thermal limits are highly dependent on each device's heat dissipation, which is related to ambient conditions. The actual flow of power through most power-system devices is already measured adequately. The need is for improved sensors or methods to dynamically determine thermal limits by directly or indirectly measuring temperature. There are several approaches/technologies for dynamic monitoring of the state of transmission lines and transformers.

Weather-Based and Predictive Line Ratings*:* The weather-based model calculates conductor temperature and ratings using only measurements of load and weather conditions. A heat-balance method is used to track conductor temperature and calculate ratings. The accuracy of the weather-based model is improved if weather stations are positioned to measure the weather actually experienced by the line. Multiple weather stations may be required if the weather changes along the line.

The weather-based model, which uses standard weather instruments, is usually the simplest method of dynamic line rating to implement. No instruments need to be mounted on the line itself, and, therefore, these instruments do not need to be designed to survive in a high-electromagnetic stress environment nor do they require taking a line out of service to install them. Load is already being measured as part of typical transmission line operations.

Confidence in this method of rating lines will improve in direct relationship to improvements in the accuracy of short-term weather forecasts. Also, historical weather and line loading data can be used to further improve this line rating technique.

Objective: Dynamically determine line capacity by calculating the sag on critical line segments using weather data and historical information
Benefits: Dynamically determined line ratings allow for increased power capacity under most operating conditions.
Barriers: The labor costs of implementing and operating weather-based dynamic line rating
Commercial Status: There is a long-standing Institute of Electrical and Electronics Engineers (IEEE) standard for calculating the current-temperature relationship of bare overhead conductors; commercial software is available that is based upon the standard. A better method to periodically take field measurements of conductor emissivity and absorptivity would improve the accuracy of this calculation method.

Direct Measurement of Conductor Sag: For overhead transmission lines, the ultimate limiting factor is usually conductor sag. As wires heat, they expand, causing the line to sag. Too much sag will eventually result in a short circuit because of arcing from the line to whatever is underneath.

Objective: Dynamically determine line capacity by directly measuring the sag on critical line segments
Benefits: Dynamically determined line ratings allow for increased power capacity under most operating conditions.
Barriers: Requires continuous monitoring of critical spans. Cost depends on the number of critical spans that must be monitored, the cost of the associated sensor technology, and the ongoing cost of communication.
Commercial Status: Pre-commercial units are currently being tested. Approaches include either video or the use of a differential global positioning system (GPS). EPRI currently is testing a video-based “sagometer.” An alternative is to use differential GPS to directly measure sag. Differential GPS has been demonstrated to be accurate for use in measuring distances to within much less than half a meter.

Indirect Measurement of Conductor Sag*:* Transmission line sag can also be estimated by physically measuring conductor temperature using an instrument directly mounted on the line and/or a second instrument that measures conductor tension at the insulator supports.

Objective: Dynamically determine the line capacity
Benefits: Dynamically determined line ratings allow for increased power capacity under most operating conditions.
Barriers: Requires continuous monitoring of critical spans. Cost depends on the number of critical spans that must be monitored, the cost of the associated sensor technology, and ongoing costs of communication.
Commercial Status: Commercial units are available.

Transformer Monitoring Systems*:* Similar to transmission line operation, substation transformer operation is limited by thermal constraints. However, substation transformer constraints are localized hot spots on the windings that result in breakdown of insulation.

Objective: Dynamically determine transformer capacity
Benefits: Dynamically determined transformer ratings allow for increased power capacity under most operating conditions.
Barriers: The simple use of oil temperature measurements is usually considered unreliable.
Commercial Status: Sophisticated monitoring tools are now commercially available that combine several different temperature and current measurements to dynamically determine temperature hot spots.

2. Real-Time Direct System-State Monitors and Wide Area Measurement Systems (WAMS)

In some situations, transmission capability is not limited by individual devices but by region-wide dynamic loadability constraints. These regional constraints include transient stability limitations, oscillatory stability limitations, and voltage stability limitations. Because the time frame associated with these phenomena is much shorter than that associated with thermal overloads, predicting, detecting, and responding to these events requires much faster real-time state sensors than are needed for thermal conditions. The system state is characterized ultimately by the voltage magnitudes and angles at all the system buses. The goal of these sensors is to provide these data at a high sampling rate.

Power-System Monitors

Objective: Collect essential signals (key power flows, bus voltages, alarms, etc.) from local monitors available to site operators, selectively forwarding to the control center or to system analysts
Benefits: Provide regional surveillance of important parts of the control system to verify system performance in real time
Barriers: Existing supervisory control and data acquisition (SCADA) and Energy Management Systems (EMS) provide low-speed data access for a utility's infrastructure. Building a network of high-speed data monitors with intra-regional breadth requires collaboration among utilities within the interconnected power system.
Commercial Status: The Bonneville Power Administration (BPA) has developed a network of dynamic monitors collecting high-speed data, first with the power system analysis monitor (PSAM), and later with the portable power system monitor (PPSM), both of which are first generation examples of WAMS products.

Wide Area Measurement Systems (WAMS)

Objective: Wide area measurement systems (WAMS) use phasor measurements that are synchronized digital transducers that can stream data, in real time, to phasor data concentrator (PDC) units. The general functions and topology of this network resemble those of dynamic monitor networks. Data quality for phasor technology appears to be very high, and secondary processing of the acquired phasors can provide a broad range of signal types.
Benefits: Phasor networks have best value in applications that are mission critical and that involve truly wide-area measurements.
Barriers: Establishing phasor measurement units (PMU) networks is straightforward and has already been demonstrated. The primary impediments are cost, reliability, and assuring value for the investment (making best use of the data collected).
Commercial Status: PMU networks have been deployed at several utilities across the country.

3. Real-Time Grid Operation and Performance Tools

Real-time grid operational tools include visualization and operator interfaces as well as increased functionalities (e.g., performance prediction, monitoring, tracking). The growing reliance on increasingly sophisticated control centers creates the need to analyze the data that are collected on a real-time basis. A particularly challenging problem is the man-machine interface, especially in light of increasing volumes of data resulting from the growth of both the transmission network and the number of power transactions. A critical issue is alarms that signify power-system disturbances.

Data visualization techniques may aid in the development of effective tools to allow operators to understand massive volumes of data with relative ease. Recent advances in computer hardware and software technology have made it possible to move beyond simple tabular displays and one-line diagrams. The ability to redraw even relatively complex displays at frame rates close to or even at full-motion video speeds opens up substantial new possibilities for dynamic one-line displays. Use of animation can produce visually appealing displays of flows, both real and reactive, and loading of lines to point out overloads.

Objective: The key research challenges associated with creating visual environments applications are the construction of appropriate systems of visual symbols or cues for the interactive display of the large amounts of power system data and methods to judge how well operators can absorb and act on the information presented. A key difficulty to overcome is the lack of “physical” visual symbols to represent critical power-system variables such as the reactive power output of a generator, the voltage at a bus, or the percentage loading of a transmission line as a function of power-transfer levels. These variables are typically presented as numerical values on a one-line diagram or in a tabular display. Research is needed to develop effective schemes to aggregate power system data for presentation in a visual environment.
Benefits: Improved grid operation can be achieved by displaying monitored data to system operators. The benefits will be realized in more efficient routine operation and greatly improved operations during non-routine events.
Barriers: Each utility system is unique, and the development of generally accepted techniques that can be applied to all utility systems may be slow, which will delay commercial deployment of a standard visual environment. Also, the process of commercialization, from R&D to demonstration and commercial production, does not usually unfold entirely within a single company; more typically, innovations move from a research university to small company to a larger company that provides products such as energy management software to utility companies.
Commercial Status: The research community is addressing the issue of data visualization for the general category of large data sets; the researchers working in this area have recognized that the power system is one key entity for whom visualization of large data sets is important. Some visualization applications are beginning to make the transition from R&D to commercial product, including applications that represent power flow, stability, voltage, and reactive power control.

4. Grid Analysis Tools

Grid analysis uses real-time data and power-system models to determine the condition of the power system. Tools include load forecasting, load flow, performance monitoring, tracking, and prediction, contingency analysis, state estimation, voltage security analysis, and transfer capability analysis.

State estimation uses on-line measurements to determine the system operating point and grid configuration at a moment in time. The state estimator provides the most up-to-date snapshot of the system and is the basis for all security assessment computations. With the growth in the number of entities whose competitive position is affected by system operating condition and grid configuration, it is easy to predict that research needs in this traditional form of power system state estimation will increase markedly; a desirable extension of the current state of the art in state estimation would be dynamic state estimation.

The voltage on the transmission system needs to be maintained within certain limits. As these limits are approached because of large power flows, especially over long lines, system voltage drops quickly (voltage collapse). Determining when the system is approaching these limits is difficult. Voltage collapse is well understood in theory; however, tools for characterizing dynamic voltage collapse and the ability of real-time controls to mitigate this collapse are much less mature.

Objective: To determine the condition of the power system using use real-time data and simulation models of the power system
Benefits: Improved transmission system operation through improved accuracy in representing system limits
Barriers: The increasingly dynamic nature of the transmission system and the increased loading of transmission lines have made the task of determining system condition more difficult. Also, increased loading means increased need for voltage control and stability analysis.
Commercial Status: Commercial products are available but have not kept pace with the changing requirements of power-system operations.

5. Communications for Transmission Systems

Power companies operate similarly to other industries with dispersed facilities and are very dependent on communications for efficient operations. The range of communications includes data and voice, both stationary and mobile.

Utility companies have built extensive fiberoptic networks for their needs. Many of the larger companies' internal communication networks span several thousand miles. Most utilities began updating their own communication networks during the 1980s and 1990s and took the unusual step of laying high-capacity fiberoptic cables along their electricity and pipeline rights-of-way. These cables gave the companies exponentially more bandwidth than they needed for their internal communications, so they have been leasing or selling the extra bandwidth.

These fiberoptic networks provide good communications capabilities to transmission substations; as a result, most of the monitored information from transmission lines comes from substations. To improve operations further, the condition of the lines between substations could be monitored; however, the difficulty of this approach is to communicate to a particular point or points along a transmission line at reasonable expense.

Objective: To develop reasonable-cost communications capabilities, both hardware and protocols, to multiple points along a transmission-line corridor
Benefits: Additional information regarding transmission-line operation will improve overall system operation.

Barriers: Capital, operating, and maintenance costs are high.
Commercial Status: Many communication technologies are available – fiberoptic, wireless, etc. – but need to be adapted to this specific application.

6. Flexible AC Transmission Systems (FACTS)

Flexible AC Transmission System (FACTS) devices use power electronics to adjust the apparent impedance of the system. FACTS devices encompass a host of power-control technologies, including the thyristor-controlled series compensator (TCSC), static synchronous compensator (STATCOM), convertible static compensator (CSC), unified power-flow controller (UPFC), and voltage source converter (VSC). Each employs thyristors in various configurations to perform different functions. Alone or in combination with one another, these devices offer much greater power grid control than has been possible in the past and operate with the speed and precision of microprocessors. Their use can greatly improve power quality while increasing line capacity by up to 40 percent.

Static Compensator (STATCOM). The STATCOM is a solid-state synchronous voltage generator, which consists of a multi-pulse, voltage-source inverter connected in shunt with the transmission line. It can counteract both voltage depression and voltage rises. Although its output characteristics are similar to those of a rotating synchronous condenser, the STATCOM responds more rapidly, does not increase short-circuit current in the system, and can provide symmetrical leading or lagging reactive current. The smooth continuous control of the STATCOM minimizes the possibility of large voltage fluctuations, which may occur with passive devices.

Unified Power Flow Controller (UPFC). The unified power flow controller (UPFC) provides simultaneous, real-time control of all three basic power-transfer parameters (voltage, impedance, and phase angle) in any combination to optimize transmitted power. It can handle conventional functions such as reactive shunt compensation, series compensation, and phase shifting. UPFCs allow power delivery system operators to set and independently control real and reactive flow.

Objective: FACTS devices are designed to control the flow of power through the transmission grid.
Benefits: These devices can increase the transfer capacity of the transmission system, support bus voltages by providing reactive power, or enhance dynamic or transient stability.
Barriers: Power electronics are expensive, and specially trained technicians are needed to maintain them. In addition, experience (and real time system data) is needed to fully understand the coordinated control strategy of these devices as they penetrate the system.
Commercial Status: The Tennessee Valley Authority (TVA) has installed a STATCOM FACTS controller, which is providing dynamic and flexible voltage and reactive power support at the Sullivan substation. The controller has enabled TVA to defer a new 160-kV transmission line and installation of a 500-kV/160-kV step-down transformer at the Sullivan Substation.

American Electric Power (AEP) installed a UPFC FACTS controller that provides voltage support at the Inez substation and dynamic power-flow control on the Big Sandy-Inez high-capacity transmission line. The controller has resulted in a 100-MW increase of power-transfer capability and a significant improvement in the quality of power supplied to a 2,000-megawatt (MW) load area.

The New York Power Authority (NYPA) is installing a CSC FACTS Controller to relieve a bottleneck at the Marcy Substation and provide power-flow control on two transmission lines. The controller is expected to increase the total Central-East power transfer capability by 240 MW without adding transmission lines.

Central & South West (now AEP) installed a VSC FACTS controller to interconnect the asynchronous U.S. and Mexico grids at the Eagle Pass substation. The controller is a voltage source converter-based back-to-back device that has allowed AEP to avoid building a long 138-kV transmission line. The interconnection provides a reliable electric bridge between the U.S. and Mexico.

7. Energy Storage

Energy storage is divided in two categories – storage for power-quality applications, which have emerged during the past 15 years, and diurnal storage, which describes traditional applications of energy storage.

Storage for power quality. Two storage mediums are used – batteries and superconducting magnetic energy storage (SMES). In a SMES system, electrical energy is stored by circulating a current in a superconducting coil or inductor. Because there is no conversion of energy to other forms (e.g., mechanical or chemical), round-trip efficiency can be very high. SMES can respond very rapidly to dump or absorb power from the grid; its response time is limited only by the switching time of the solid-state components doing the DC/AC conversion and connecting the coil to the grid. The battery system works similarly; the energy is stored in chemical form and converted from DC/AC using a power electronic system. The batteries are carefully sized for response-time and peak-power requirements.

Objective: To improve power quality on the transmission and distribution system by injecting power in response to anomalous events such as voltage sags and power surges.
Benefits: For the transmission system, energy storage systems are a tool similar to FACTS devices for mitigating real and reactive power-flow problems. For loads requiring a high degree of power quality, an energy storage system can be used at the customer's site.
Barriers: The technical feasibility of SMES and battery systems for power quality applications has been shown, and improvements are continuing, allowing the systems to respond to a broader range of system events. The economic costs and benefits of energy storage for power quality are still being proven.
Commercial Status: To date, the SMES systems have been based on low-temperature superconducting materials; systems using high-temperature materials are in development. In the early 1980s, a SMES system was built to suppress voltage fluctuations in the West Coast grid but its operation was limited because of inadequacies in the cooling system. As part of the "Star Wars" missile defense system plans, a 21 MWh SMES was designed between 1986 and 1992 but

was never built. Utility system applications for this large SMES were investigated, but were not pursued. A 0.5-MWh SMES was proposed for use in Alaska to stabilize the local power grid, but it appears that lower natural gas prices made the project difficult to justify economically.

Smaller mobile SMES systems [~ 3 MW/3 megajoule (MJ)] were commercially introduced by Superconductivity Inc., (now owned by American Superconductor) during the mid-1990s to provide improved power quality at industrial production sites.

Diurnal storage. Traditional energy storage devices/methods include batteries, pumped hydro, and compressed air. The traditional function of these devices is to save production costs by holding cheaply generated off-peak energy that can be dispatched during peak-consumption periods. With modest incremental investment, energy storage can also be used to provide effective power system control. Different dispatch modes can be superimposed on the daily cycle of energy storage, and additional capacity can be reserved for the express purpose of providing these control functions.

Objective: Store energy generated in off-peak hours to be used for emergencies or on-peak needs. This technology helps shave peaks and can help in light-load, high-voltage situations.
Benefits: These storage systems behave like conventional generation and have the benefit of being useful as additional generation sources that can be dispatched to meet system energy and power needs. Storing energy produced by base generation units in off-peak periods can avoid the need to use highly polluting supplemental/peak generation units during periods of peak demand. As a distributed resource, energy storage devices can enhance power quality and reliability.
Barriers: The capital cost and maintenance of energy storage devices have limited their impact. The loss of efficiency between charge and discharge must be outweighed by the benefits.
Commercial Status: Several pump storage plants are operating across the country, including as 1,600-MW Raccoon Mountain facility owned by TVA. Battery and compressed air energy storage systems have been demonstrated. One of the early battery installations that demonstrated a benefit to the grid was a 10-MW system at Southern California Edison's Chino substation.

8. Ultra-High Voltage (UHV)

Because power is equal to the product of voltage times current, a highly effective approach to increasing the amount of power transmitted on a transmission line is to increase its operating voltage. Since 1969, the highest transmission voltage levels in North America have been 765 kV.

Objective: Increasing the voltage level to increase the rating of a transmission line. Transmission voltages in the U.S. range from 115 kV to 765 kV.
Benefits: As the voltage level increases, the power density of a right-of-way increases as a function of the voltage squared. For example, a doubling of the voltage level increases the power density by a factor of four.
Barriers: The challenges of utilizing higher voltages include the need for larger towers and larger rights-of-way to get necessary phase separation, the ionization of air near the surface of the

conductors because of high electric fields, the high reactive power generation of the lines, and public concerns about EMFs.
Commercial Status: In the U.S., UHV was being developed during the 1970s but was abandoned when load growth dropped and eliminated the need for increased voltages. Development of UHV (1,100-kV) technology continues in other countries, notably Japan where a UHV line is being constructed in sections and operated initially at a lower voltage.

9. High-Voltage DC (HVDC)

With active control of real and reactive power transfer, HVDC can be modulated to damp oscillations or provide power-flow dispatch independent of voltage magnitudes or angles (unlike in conventional AC transmission).

Objective: Long-distance power transport linking asynchronous control areas; real-time control of power flow.
Benefits: Stable transport of power over long distances where AC transmission lines need series compensation that can lead to stability problems. HVDC can run independent of system frequency and can control the amount of power sent through a line. This latter benefit is the same as for FACTS devices discussed elsewhere in this Appendix.
Barriers: Drawbacks include the high cost of converter equipment and the need for specially trained technicians to maintain the devices.
Commercial Status: Many long-distance HVDC links are in place around the world. Back-to-back converters link Texas, WSCC, and the Eastern Interconnection in the U.S. More installations are being planned.

10. Underground Cables

The state of the art in underground cables includes fluid-filled polypropylene paper laminate (PPL) and extruded dielectric polyethylene (XLPE) cables. Other approaches, such as gas-insulated lines (GILs), are being researched and are promising for future applications.

Objective: Transmit power in areas where overhead transmission is impractical or unpopular
Benefits: Compared to aboveground cable, underground cable has the advantages of being protected from weather and thus has longer lifetimes and reduced maintenance. Underground cables also reduce EMFs and the visual pollution associated with transmission lines.
Barriers: Drawbacks include costs that are five to 10 times more than those of overhead transmission and challenges in repairing and replacing underground cables when problems arise. Nonetheless, underground cables have made great technical advances and the cost is decreasing (the typical cost ratio a decade ago was 20 to one).
Commercial Status: PPL cable technology is more mature than XLPE. Extra high voltage (EHV) AC and HVDC applications exist throughout the world. XLPE is gaining quickly and has advantages: low dielectric losses, simple maintenance, no insulating fluid to affect the environment in the event of system failure, and ever-smaller insulation thicknesses. GILs feature a relatively large-diameter tubular conductor sized for the gas insulation and surrounded by a solid metal sleeve. This configuration translates to lower resistive and capacitive losses, no

external EMFs, good cooling properties, and reduced total life-cycle costs compared with other types of cables. This type of transmission line is installed in segments joined with orbital welders and run through tunnels. This line is less flexible than the PPL or XLPE cables and is, thus far, experimental and significantly more expensive than those two alternatives.

Underwater application of electric cable technology has a long history. Installations are numerous between mainland Europe, Scandinavia, and Great Britain. This technology is also well suited to electricity systems linking islands and peninsulas, such as in Southeast Asia. The planned Neptune Project consists of a network of underwater cables proposed to link Maine and Canada Maritime generation with the rest of New England, New York, and the mid-Atlantic areas.

Underground/Submarine Cable Monitoring/Diagnostics: The below-surface cable systems described above require real-time monitoring to maximize their use and warn of potential failure.

Objective: Incorporate real-time sensing equipment to detect potentially hazardous operating situations as well as dynamic limits for safe flow of energy.
Benefits: Monitoring equipment maximizes the use of the transmission asset, mitigates the risk of failure and the ensuing expense of repair, and supports preventive maintenance procedures. The basic sensing and monitoring technology is available today.
Barriers: The sophistication of the sensing and monitoring equipment adds to the cost of the cable system. The use of dynamic limits must also be integrated into system operation procedures and the associated tools of existing control facilities.
Commercial Status: Newer cable systems are being designed with monitoring/diagnostics in mind. Cable temperature, dynamic thermal rating calculations, partial discharge detection, moisture penetration, cable damage, hydraulic condition (as appropriate), and loss detection are some of the sensing functions being put in place. Multifunctional cables (particularly submarine cables) are also being designed and deployed that include communications capabilities. Monitoring capabilities are being integrated directly into the manufacturing process of these cables.

11. Transmission Tower Design Tools

Advances are being made in the configuration of transmission lines. New design processes coupled with powerful computer programs can optimize the height, strength, and positioning of transmission towers, insulators, and associated equipment to meet engineering standards appropriate for the conductor (e.g., distance from ground and tension for a given set of weather parameters). A set of tools is being perfected to analyze upgrades to existing transmission facilities or installation of new facilities to increase their power-transfer capacity and reduce maintenance.

Objective: Ease of use and greater application of visualization techniques to make the design process more efficient and accurate than has been possible in the past. Traditionally, lines have been rated conservatively. Careful analysis can discover the unused potential of existing

facilities. Visualization tools can show the public the anticipated visual impact of a planned project.
Benefits: Avoids new right-of-way issues. The cost of upgrading the thermal rating of a line has been estimated at approximately $7,000 per circuit mile, which is much less than the cost of re-conductoring a 230-kV circuit ($120,000 per mile) or building a new steel-pole circuit ($230,000 per mile).
Barriers: This technology is making good inroads; barriers are minimal.
Commercial Status: Several companies offer commercial products and services.

12. Advanced Composite Conductors

Usually, transmission lines contain steel-core cables that support strands of aluminum wires, which are the primary conductors of electricity. New cores developed from composite materials are proposed to replace steel cores.

Objective: Allow more power through new or existing transmission rights-of-way.
Benefits: A new core consisting of composite fiber materials shows promise as stronger than steel-core aluminum conductors and is 50 percent lighter in weight with up to 2.5 times less sag. The reduced weight and higher strength mean greater current-carrying capability because more current-carrying aluminum can be added to the line. This fact, along with manufacturing advances such as trapezoidal shaping of the aluminum strands, can reduce resistance by 10 percent, enable more compact designs with up to 50-percent reduction in magnetic fields, and reduce ice buildup compared what is true for standard wire conductors. This technology can be integrated in the field by most existing reconductoring equipment.
Barriers: More experience is needed with the new composite cores to reduce the total cost of owning and operating this technology.
Commercial Status: Research projects and test systems are under way.

13. Standardized, Modular Equipment

One way to gain flexibility for changing market and operational situations is to develop standards for the manufacture and integration of modular equipment.

Objective: Develop substation designs and specifications for equipment manufacturers to meet; these designs/specifications should facilitate the movement and reconfiguration of equipment in a substation to meet changing needs. Also, develop a single, standardized transformer design capable of handling multiple voltage transformations in the mid ranges of 161/230/345/500 kV on a switch-selectable basis. Added features might be high portability to facilitate emergency deployment from a “strategic reserve” of such transformers, plus the accommodation of high-phase-order transmission lines.
Benefits: Reduce overall the time and expense for transmission systems to adapt to the changing economic and reliability landscape.
Barriers: Process would require transmission planners and substation designers to consider a broad range of operating scenarios. Also, developing industry standards can take a significant period of time, and manufacturers would need to offer conforming products.

Commercial Status: Utilities have looked for some standardization and flexibility in this area for some time; however, further work remains to be done. The National Grid in the United Kingdom has configured a number of voltage-support devices that use modular construction methods. As the system evolves, the equipment can be moved to locations where support is needed.

14. High-Temperature Superconducting (HTSC) Technology

The conductors in HTSC devices operate at extremely low resistances. They require refrigeration (generally liquid nitrogen) to super-cool superconducting ceramic material.

Objective: Transmit more power in existing or smaller rights-of-way. Used for transmission lines, transformers, reactors, capacitors, and current limiters.
Benefits: Fewer cables are needed and less space is required to support a given level of power transfer (AC transmission lines bundle three phase together; transformers and other equipment occupy smaller footprint for same capacity). Cables can be buried to reduce exposure to EMFs and avoid visual pollution. Transformers can reduce or eliminate cooling oils that, if spilled, can damage the environment. The HTSC itself can have a long lifetime, sharing the properties noted for surface cables below.
Barriers: Maintenance costs are high (refrigeration equipment is required, which demands trained technicians with new skills; the complexity of the system can result in a larger number of failures than for current equipment; power surges can quench (terminate) superconducting properties equipment, and therefore requires more advanced protection schemes).
Commercial Status: The technology is in the demonstration phase. Two superconducting cable demonstrations are in operation: a cold-dielectric design by Southwire Company at its headquarters in Carrollton, Georgia and a warm-dielectric design by NKT Cables in Denmark. A fault current limiter has been built and briefly tested at Southern California Edison. A transformer has been built and is being tested by Waukesha Electric Systems in Wisconsin.

15. Polyphase Transmission Line Configurations

The concept of increasing the power density of a right-of-way by using more than three phases has been under consideration for some time. Using six or even 12 phases allows for greater power-transfer capability within a particular right-of-way and reduces EMFs because of greater phase cancellation.

An existing double-circuit 115-kV line was converted to 93-kV, six-phase and operated for three years (1992-1995) on the New York State Electric and Gas (NYSEG) system near Binghamton, New York. In addition to NYSEG, project sponsors were the Empire State Electric Energy Research Co., DOE, NYSERDA, and EPRI. The demonstration project showed that utilities could consider use of high-phase-order lines in their transmission systems.

Objective: Use high-phase-order transmission to increase the power density of a transmission corridor by raising the voltage

Benefits: When an existing double-circuit three-phase line is converted to six-phase operation, the line-to-line voltages can remain the same, and the line-to-ground voltages can be increased up to the line-to-line level. The power rating could be increased by up to 73 percent.
Barriers: High phase order is not the answer for all transmission problems, but it is a useful technique for addressing constraints imposed on a line by other factors, such as space limitations.
Commercial Status: A six-phase line as been successfully operated for three years, demonstrating the value of this concept.

16. Advanced Real-Time Control Technologies and Approaches

From its inception, the power system has had to operate in a real-time mode because electricity generation must match demand, moment by moment. Initially, real-time control consisted of simple generation control with full-time operators at generating stations and substations communicating by telephone. Today, there are sophisticated electronic control systems at generating stations and substations, remote control of equipment at most facilities, an extensive communications network for both voice and data, and the ability to simulate and model the system using computers and real-time data. The concepts and abilities of real-time control continue to progress, striving to keep pace with the growing complexity of the power generation and delivery system.

Many transmission system devices exercise real-time control on the grid, such as protective relaying and circuit breakers, voltage and reactive power control (switched capacitor banks, static VAR compensators, and synchronous condensers), and real power control (HVDC converters and FACTS devices). With the restructuring of the utility industry, the responsibilities for generation, transmission, and distribution are being separated, and there is an increased need to ensure that operation of these systems remains coordinated. For example, one means of controlling line flows is by adjusting the output of generating plants. What once was a coordinated move within one company will, in the restructured industry, involve at least two separate companies or organizations. To cope with these changes, additional real-time control features and hardware may be necessary. Also, as transmission lines and other equipment are operated closer to their limits, additional monitoring and control equipment will be needed to maximize the productivity of these facilities. With these changes to the transmission system occurring, the operating philosophy must make a transition to focus on maintaining and increasing reliability and economy.

Today’s power system has generating units that range in size from 1,200-MW nuclear plants to units that are 40,000 times smaller, such as 30-kW microturbines or windmills. Today’s technology allows control of each individual unit, but how is this control is implemented? For example, a wind farm consisting of 200 windmills can look like a single unit to the power system operator if there is a control agent at the wind farm that can control each individual windmill in an integrated manner. A multitude of strategies can be employed, such as maximum output if the overall system is short of generation or minimum fluctuations of the overall wind farm output to minimize response by other generating units. The windfarm control agent can have the ability to monitor the power system locally or receive remote information and then act by controlling each windmill. The power system is evolving as a combination of centralized and decentralized control and developing and designing the control system continues to be a challenge.

On the load side, there is also a similar range of possibility as very large industrial customers are routinely being controlled for the benefit of the overall power system and loads as small as a five-kilowatt residential air conditioner can also be controlled using a "smart" thermostat with an embedded pager system. With these capabilities, it is now possible to automatically control or dispatch load just as is done with generation.

Objective: To continue the development of real-time control technologies and approaches by bringing modern control theory to practical application. Specific areas include wider use of centralized and decentralized control using distributed control agents and integration of customer demand into the automatic control and dispatch of the power system.
Benefits: Improved capabilities to monitor and control load and generation will further optimize overall system operation, yielding lower electricity costs.
Barriers: Continuation in the reduction of communications costs will further enable the adoption of more real-time control applications, especially at the customer level where the number of communication points is large. Rate structures need to be developed and adopted to provide the incentive for controlling generation or loads.
Commercial Status: Current commercial status ranges from concepts and simulations to in-progress small-scale experiments and demonstrations.

17. Tools for Market Design, Performance Assessment, Analysis, and Monitoring

The transition of the electric power industry from a regulated monopoly to an unbundled set of production, transmission, and distribution businesses has forced an examination what of constitutes market power and how the market should operate. The issues surrounding design of power markets are complex, with potentially costly implications for a diversity of stakeholders. Challenges range from the determining the structure and timing of bidding in wholesale energy markets to designing transmission tariffs and congestion charges to assessing market power and trading in ancillary services. Traditional modeling tools are limited in their application to electricity markets because of the difficulty in defining the market as it is evolving.
Market analysis and simulation tools are used for many different purposes including:

- Determining the impact of market design decisions and rule changes
- Developing market price projections for various scenarios of load growth and entry of new generators
- Valuing generation and transmission assets
- Optimizing trading strategies for a portfolio of generation and transmission assets
- Modeling day-to-day bidding and generation-unit dispatch decisions
- Determining the optimal size and timing of new investments
- Projecting short-, medium-, and long-term capacity adequacy
- Analyzing generation and transmission constraints
- Optimizing the timing and duration of maintenance outages
- Assessing the impact of security-of-supply and environmental constraints
- Determining market outcomes that account for both variable and fixed cost components

Objective: Devising tools for analyzing and monitoring market designs to ensure effective design and execution.
Benefits: The benefits of using market tools include 1) increasing wholesale choice and services, 2) reducing delivered price through decreased transaction costs and expanded markets 3) improving system reliability, 4) expediting infrastructure improvements, 5) increasing market certainty, 5) increasing operating and maintenance efficiencies, and 6) identifying planning and investment opportunities.
Barriers: The complexity of the market translates into complex modeling and analysis.
Commercial Status: Consultants are providing services and introducing market design tools and techniques from other industries, which are modified and applied as appropriate.

18. Transmission Expansion Planning Tools and Approaches

Transmission expansion includes all reinforcements (additions, modifications, or upgrades) of the transmission system, including all related equipment and facilities. Transmission is usually expanded to increase the power transfer capability of the transmission system and/or to maintain adequate reliability of the interconnected electricity systems. Transmission planning is the process of determining which changes to make in the system.

Expanding transmission capacity requires good planning plus appropriate market rules and regulatory oversight. Historically, state public utility commissions oversaw utility planning and construction of new transmission facilities. In a restructured electricity industry, FERC will have much greater influence over planning and expansion. During the current transition to a fully competitive electricity industry, regulatory authority to ensure construction of needed transmission facilities is fragmented.

Today, more than half of the electricity generated in the U.S. is traded in regional wholesale markets before being delivered to the end-use customer. In this new landscape, different companies increasingly provide generation and transmission. This shift from local to regional markets and monopoly supply to wholesale competition complicates how states plan for, certify, and site transmission infrastructure. Some of the challenges include:

- Clarifying the roles and authorities in regional transmission planning process,
- Determining need for new transmission infrastructure,
- Allocating the costs of new transmission lines, and
- Coordinating the review and permitting of interstate transmission lines.

Objective: Continue to refine and develop the transmission planning and expansion process in a deregulated utility industry, including developing using new and novel analytical techniques.
Benefits: The benefits include: maintaining reliability in an economic manner, identifying system limitations, avoiding unnecessary duplication of facilities, and providing for coordination with all parties involved in transmission system operation and use.
Barriers: Determining the realm of the new transmission expansion planning process as the industry is changing structure. The new emphasis is on a regional planning process with more organizations involved.

Commercial Status: Commercial products have been developed over many years to assist in the transmission expansion planning process. As the process evolves, consulting and utility service companies are introducing new tools and approaches to improve the process.

19. Assessment of Public Safety, Environmental and Health Effects

In order to generate, transmit, and distribute electric power, a utility must maintain a complex, geographically distributed infrastructure of generation facilities, remote substations, transmission towers, and other components. To ensure public safety, the system and equipment must function reliably and predictably. The consequences of failures can be severe, and the interrelated nature of the power transmission and delivery infrastructure makes prolonged downtime at even a remote facility unacceptable because a breakdown in one location can rapidly affect others.

Objective: To ensure the health and safety in the production and delivery of electricity
Benefits: Increased public health and safety
Barriers: As the utility industry is deregulated, the focus on public safety and environmental and health effects continues in priority. However, ensuring that this focus continues as the roles and responsibilities of the industry change is not certain.
Commercial Status: Not applicable

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